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# Offshore storage options for $CO_2$ in the Netherlands

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**Abstract**

This paper presents the results from an assessment of high-capacity storage options in the offshore area of The Netherlands. For deep saline formations, available regional geological maps were combined with fault structures derived from seismic data to reveal the compartmentalization of prospective reservoir formations. Adding knowledge concerning these formations from offshore oil and gas activities and concerning the behavior of gas fields located in these formations, resulted in a shortlist of lowest-risk, potential storage locations with a total theoretical capacity of about 1.5 $GtCO_2$. A high-level risk analysis was performed for offshore gas fields. The largest offshore gas fields add another 350 $MtCO_2$. The development of saline formations and gas fields is outlined; while a gas field can be converted from production to storage in 5-6 yrs, it takes at least 7 yrs to develop $CO_2$ storage in a saline formation that has not been accessed before for hydrocarbon production.


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*Keywords:* $CO_2$ storage, saline formations, site development

## 1. Introduction

In early 2010, the Rotterdam Climate Initiative (RCI) contracted TNO Built Environment and Geosciences (TNO) to conduct an Independent $CO_2$ Storage Assessment (ISA) of offshore $CO_2$ storage sites under the Dutch North Sea, so as to support the early deployment of carbon capture and storage (CCS) in the Netherlands. The ISA was conducted in three phases, with this paper summarizing Phase 3. Phases 1 and 2 are covered in separate reports, one detailing the methodology employed [1] and one presenting the results [2].

The ISA studies are intended to provide a comprehensive view of potential offshore $CO_2$ storage in The Netherlands, with the specific goals of:

- ensuring that planning for $CO_2$ storage does not lag behind planning of other portions of the CCS value chain;

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- identifying and progressing work on several potential $CO_2$ storage sites, to provide sufficient alternatives should individual sites prove to be unavailable on desired timelines or prove less attractive during later stage work;
- providing greater certainty among emitters regarding storage availability and capacity, enhancing their confidence in planning $CO_2$ capture projects; and

ISA Phases 1 and 2 sought to support first-mover CCS projects by providing detailed assessment of the most promising prospective $CO_2$ storage sites available between 2015-2020. Phase 1 screened the offshore area close to Rotterdam to identify the most attractive options; phase 2 then performed detailed site characterisation of the four most attractive prospects (one of these is the P18 field, which is the intended storage for the ROAD demonstration project [3].

The aim of the present study, ISA Phase 3, is to provide an outlook on longer-term offshore storage, seeking to identify high-capacity $CO_2$ storage sites throughout the entire Dutch Continental Shelf, irrespective of their location and of the timing of their availability. These high-capacity sites can be seen as representing the $CO_2$ storage capacity for the larger volumes of $CO_2$ anticipated with the commercialization of CCS.

This paper presents the main conclusions from the study; more detail can be found in the full report [4]. The development of a saline formation for injection and storage of $CO_2$ is described in Appendix A; a comparison is made with the steps required to convert (the installations of) a depleted gas field for $CO_2$ storage.

## 2. Method

ISA Phase 3 screened all potential geological structures, including saline formations and depleting hydrocarbon fields in the entire Dutch Continental Shelf. Lower $CO_2$ storage capacity thresholds were set at 50 Mt for saline formations and 40 Mt for gas fields. These arbitrary limits were selected based on a review of existing storage capacity rankings of gas fields on the Dutch continental shelf (DCS) by size. A short discussion of the general approach taken is given below.

*Saline formations.* The aim of the present study was to identify large, connected volumes (compartments) of saline formations. No analysis was done to reveal structurally favourable locations, such as local anticlines or fault traps, as was done in previous studies [5]. To find these connected volumes and to assess the feasibility of storage, a number of elements were combined:

- Structural models of the deep geology, revealing the occurrence and extent of potential reservoir formations;
- Maps of faults intersecting the reservoir formations, which define compartment size;
- Knowledge of the behaviour of gas fields located in these formations, as an independent indicator of the size of compartments;
- Knowledge of the geological history of the area, providing information on reservoir quality (which provides the information to estimate storage rates, in Mt/yr).

The result from this approach is a number of compartments within the potential storage formations that could be used for $CO_2$ storage. The feasibility of storage of the $CO_2$ within a storage compartment is to be addressed as part of a more detailed analysis of each compartment.

The implicit assumption in the present study is that storage capacity is created by increasing the pressure in the formation and using the compressibility of the reservoir system. An alternative approach would be to assume the production (extraction) of the saline formation fluids to be replaced with $CO_2$. This has the advantage that even a relatively small compartment can provide a large storage capacity. However, it is currently not clear whether this assumption is realistic and feasible as the ease with which the formation fluids can be disposed of will, inter alia, depend on their [particular] composition. The capacity figures reported here can therefore be seen as conservative estimates; higher storage capacities can be reached, but only when formation water production is feasible.

*Depleted gas fields.* The gas fields in the DCS have been well documented in previous studies, including in previous phases of the ISA. With the exception of setting a minimum storage capacity threshold of 40 Mt, the approach taken in ISA Phase 3 is identical to that taken in ISA Phase 1 and is described in detail in [1]. Injection rates were estimated from available data on reservoir quality, using different numbers of injectors to obtain low, medium and high rates. Publicly available data on the largest offshore gas fields were used to identify possible issues, such as the presence of abandoned wells (a significant risk factor), the age of the infrastructure and the expected year of end of production. The offshore gas fields are linked by pipelines in a number of clusters, with the large gas fields at the centre; this structure can also be used during injection. The expected year of end of production and platform age was also collected for the smaller fields in each cluster.

Table. 1. High-capacity $CO_2$ storage options in the Netherlands offshore: saline formation (1 through 5) and gas fields (6 through 9). Storage capacity estimates for option 6 through 9 are given for the cluster of smaller fields associated with the large fields; the capacity of the large, central gas field is given in brackets. The location of the storage options is given in Figure 1. Availability of the options is shown in Figure 2.

| **Saline formation** | **Capacity (Mt)** | **First-order estimate injectivity** | **Issues** | **Minimum Development Time** |
|---|---|---|---|---|
| **1. Q1 - Lower Cretaceous** | 110 - 225 | Good: up to 10 Mt/yr | Well integrity; possible re-use | 5 years |
| **2. P, Q - Lower Cretaceous** | 360 | Good: up to 10 Mt/yr | Interference with h/c production. | 6-7 years |
| **3. F15, F18 – Triassic** | 650 | 1-3 Mt/yr | Interference with h/c production.; overpressure; low permeability | 6-7 years |
| **4. L10, L13 – Upper Rotliegend** | 60 | 5 Mt/yt | Interference with h/c production. | 6-7 years |
| **5. Step graben – Triassic** | 190 | 1-3 Mt/yr | Interference with h/c production.; low permeability | 6-7 years |
| **Gas field (gas field cluster)** | **Capacity (Mt)** | **Plateau injection rates ($MtCO_2$/yr)** | **Overall Complexity and Risk** | **Minimum Development Time** |
| **6. K14/15** | 165 (54 for K15-FB) | 3 [15-20 yrs]<br>6 [5-10 yrs]<br>9 [5 yrs] | Low – multiple fields and aging infrastructure, but low well integrity risks; single operator and well-known geology | 6 years |
| **7. K04/05** | 140 (40 for K05a-A) | 2 [19 yr]<br>3 [12 yr]<br>5 [6 yr] | Low – multiple fields, but relatively modern infrastructure; late availability allows learning from earlier projects | 6 years |
| **8. K07/08/10** | 195 (130 for K08-FA) | 3-6 [20+ yrs]<br>6-12 [10+ yrs]<br>9-18 [5+ yrs] | Moderate – multiple fields and ageing infrastructure, but relatively few blocks account for most capacity; several old, abandoned wells | 6 years |
| **9. L10/K12** | 175 (125 for L10-CD) | 6 [17 yrs]<br>9 [10 yrs]<br>12 [4 yrs] | High –abandoned wells, aging installations, some fields in cluster already almost depleted | > 6 years |

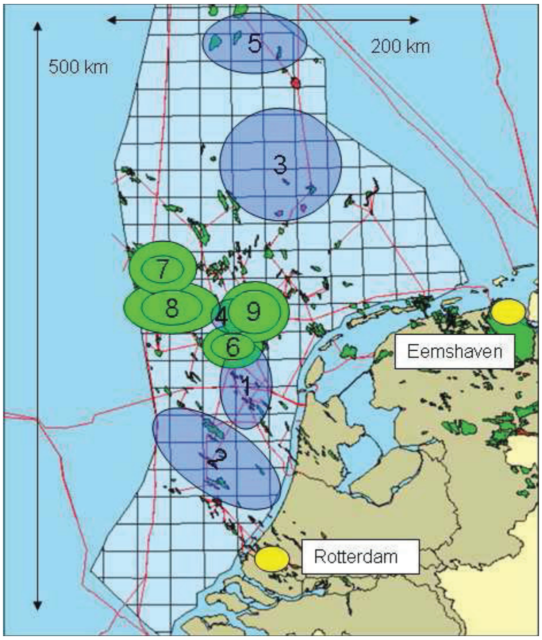


Fig. 1. Location of the high-capacity $CO_2$ storage options in the Netherlands offshore. The numbers refer to Tables 1 and Figure 2.

## 3. Results: high-capacity $CO_2$ storage options

The high-capacity storage options in the DCS are shown in Figure 1, colour coded for the type of structure (green: gas field, blue: saline formation). The size of the circle is a measure of the estimated storage capacity.

*Saline formations*. The total storage capacity represented by the saline formations identified in this study is about 1.5 Gt. This storage potential falls in the lowest, most uncertain, part of the CSLF storage pyramid. All saline formation options shown in the figure represent good options, but with low certainty. Due to the lack of detailed data on the properties of the structures, the result of the analyses is an estimate of the likelihood that a particular option will prove to be successful; the five formations shown here represent the ones most likely to be successful. The formation '1' has the lowest uncertainty. Due to the production of oil fields within the formation, the level of knowledge on this structure is comparable to that of gas fields; a detailed characterization study has already been performed.

*Gas fields*. The gas field storage potential, represented by the largest offshore gas fields, is about 350 Mt, while the potential in the gas field clusters associated with these fields is about 675 Mt. The total offshore storage capacity has been estimated at about 800 Mt [6]. The results given in this paper can be used to give a first-order estimate of the risk level for developing the fields for storage of $CO_2$, such as the presence of abandoned wells, ageing installations.

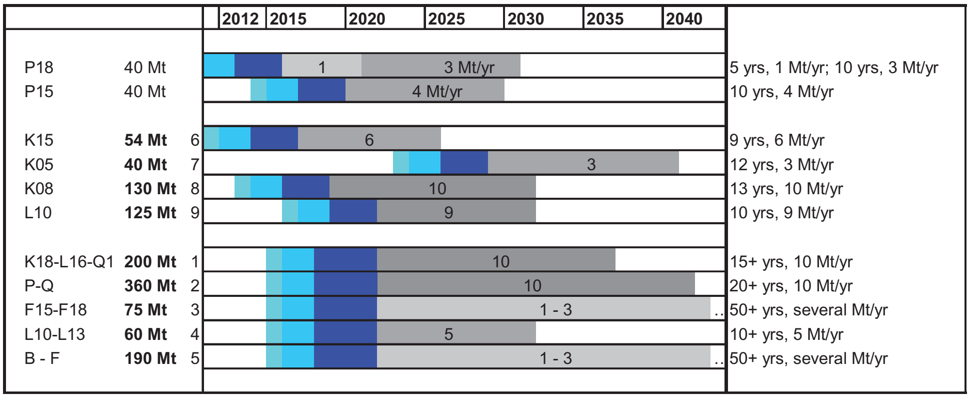


Fig. 2. Availability of the offshore $CO_2$ storage options on a timeline. Blue colours represent development phases; grey colours indicate estimated injection rates. The numbers on the left refer to Table 1 and Figure 1.

## 4. CCS development

The suitability of the options identified depends on many factors, of which availability, capacity and feasible storage rates are addressed in this study. Figure 2 shows a timeline extending from 2011 to 2045, with the possible injection periods and storage rates for each of the storage options. The P18 gas field, which is currently being developed for $CO_2$ storage as part of the ROAD project, is shown in the figure, at first for the rate relevant for the demonstration project (about 1 Mt/yr), later at a higher, post-demo phase rate. The P15 gas field, located close to the P18 field, is a candidate site for storage when $CO_2$ volumes exceed the capability of the P18 field. These two sites are included in the figure, representing short-term storage solutions.

*Gas fields*. The currently estimated availability of the gas fields is used to locate the gas fields on the timeline. The medium storage rate (see Table 1) is used to give an indication of the duration of injection (grey bars in Figure 2). The figure shows that, using the data available in this study and assuming that delaying the start of injection is possible, a total storage rate in the gas fields in the range of 20 – 30 Mt/yr is feasible. Utilizing this potential involves constructing a pipeline to the K and L blocks (approximately 150 km from Rotterdam, up to 200 km from Eemshaven, in the north of the country).

The steps involved in developing the gas fields for $CO_2$ storage are listed in Appendix A. The associated timeline is 5 – 6 years (minimum), depending on the size of the field and the complexity of the workover required on existing installations (wells, platforms, pipelines). This period is measured from the start of the detailed site characterization to the start of injection; it is indicated in Figure 2 by the blue bars. Most of this work can be done during the last phase of production, to optimize the conversion from production to storage and to minimize any idle time of fields and installations. At present it is not clear whether injection into a number of depleted gas fields can be done with a subsea installation, or whether (small) platforms are required for processing of the $CO_2$ prior to injection. The former obviously results in lower complexity, lower costs and, likely greater flexibility in maintaining fields between cessation of production and start of injection.

*Saline formations*. For the saline formations it is assumed that injection starts in the period 2020 – 2025. If all five structures were to start simultaneously, a similar total injection rate (20 – 30 Mt/yr) should be feasible. However, these options are distributed all over the DCS and utilizing their full potential involves several long pipelines, or ship transport. Two storage options are located close to Rotterdam, in the lower Cretaceous in the P and Q blocks (options ‘1’ and ‘2’). With a total estimated storage capacity of about 500 Mt and total storage rates of the order of 10 – 20 Mt/yr, these two options can provide a solution for commercial-scale CCS for a considerable period of time.

The steps towards the development of saline formations for $CO_2$ storage differ between the formation ‘1’ and the other options. As the formation ‘1’ is associated with the oil production from several oil fields, its status in terms of data availability is comparable to that of a depleted gas field and the situation described above applies. In addition, studies are already being undertaken by the operator. For the other saline formations, the next steps in essence involve an exploration effort quite similar to, but different in emphasis and details from that for a hydrocarbon field. The steps are explained in Appendix A.

## 5. Conclusion

This study shows that there are several high-capacity storage options for $CO_2$ in the Netherlands offshore. The largest gas fields have a storage capacity of the order of 100 Mt and are available around 2020. The time needed to develop these fields for $CO_2$ storage is estimated to be in the range of 5 – 10 years. The cost involved for these fields strongly depends on the results of the first demonstration projects, which will show which installations are required for injection into depleted gas fields.

A number of high-capacity saline formations favorable for $CO_2$ storage have been found. While gas exploration and production efforts have resulted in a high level of knowledge on gas fields, only little detailed information is available for these saline formations. A full-scale exploration effort is required to obtain the information for a thorough risk analysis of these options.

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## Appendix A. Site development – virgin saline formations

The saline formations studied in this paper are all virgin formations (with one exception), which means that the formations have not been used for or are not associated with previous hydrocarbon production activities. It is important to note that in a screening study such as this, in which both saline formations and depleted gas fields are considered, the starting point for (virgin) saline formations is significantly different from that for depleted gas fields. For the latter, the exploration and production of hydrocarbons has resulted in a detailed knowledge of the reservoir (gas field) and the feasibility of $CO_2$ storage can be established with available data. For virgin saline formations in the DCS, the starting point is often only a regional geological model derived from seismic data. To arrive at a roughly similarposition regarding knowledge on the potential reservoir as in the case of gas fields, a full exploration effort must be performed, including the drilling of one or more exploration wells.

### *A.1. Workflow*

The general workflow including timeline given in Table A.1 sketches the steps towards developing a virgin saline formation from first identification (as in this study) to start of injection. The timeline assumes that several of the activities can be performed in parallel. The site development is broken up into three phases. The decision gates (DG0, DG1 and DG2) associated with these phases involve increasingly higher budgets. At each decision gate, the level of knowledge about the risks associated with the storage system is improved and the uncertainties are smaller.

*DG0*. This is the decision to start a feasibility study, following selection of the site after a screening study. The budget to be decided on is up to about 4 M€, in case no seismic data is available, or up to about 1 M€, in case existing seismic data is to be re-interpreted.

Phase 1. The first phase typically takes about 2 years (if a seismic survey is included), or about 1 year (if existing data are used).

*DG1*. This decision concerns the drilling of an exploration well. The budget involved is about 20 M€.

Phase 2. The second phase takes typically 2.5 years.

*DG2*. The results from the exploration well are used to decide on the development of the site: platform or subsea completion, pipelines. The budget involved is of the order of 85 M€.

Phase 3. The third phase is the phase with longest duration, at least 3 – 4 years.

### *A.2. Site (field or cluster) feasibility study*

The data required for a rigorous feasibility study, steps 3 and 5 in Table A 1, is usually available for a depleted gas field (although perhaps not all in the public domain), but not for a saline formation. For the latter, data is collected in two steps: from regional models of the subsurface, with additional data from nearby hydrocarbon exploration and production activities (if any), in step 3, plus data obtained from an exploration well (step 5). The set-up of a feasibility, or site characterization, study is described in a separate paper [7].

*A.3. Costs*

The costs given in the above workflow strongly depend on the area covered. Exploration for and a qualification of a saline formation for $CO_2$ storage generally deals with (very) large areas and subsurface volumes. The time needed to complete the seismic surveys, to process the seismic data and to perform a site qualification study is longer than similar activities dealing with gas fields. This explains the range in the time needed listed for each step. A similar uncertainty is associated with the estimate of the costs of development. The cost given represents only the up-front investment cost; operational expenditures during the project are not given.

This list results in a total cost of developing a virgin saline formation (i.e., not previously associated with hydrocarbon production) for injection of $CO_2$, at a single injection location. The major cost elements are the new wells and the construction of a platform. In this example two new wells are drilled; in some cases in hydrocarbon exploration and production the exploration well can be used for production, which in this case would reduce the costs by about 20 M€.

Table.A.1. Development timeline for a saline formation, with a high-level cost estimate.

| | *Activity* | *Time needed (includes lead times)* | *Cost estimate* | *Comment* |
|---|---|---|---|---|
| | **Decision gate DG0: 1 – 4 M€** | | | |
| Phase 1 | 1. Acquisition of high resolution seismic data, or re-processing of existing 3D data | 1 yr | 1 M€ | Specialised contractor: €15-20 k€/ km². Re-processing 3D data: €1.5k / km², area used: 20x20 km² |
| | 2. Processing of seismic data | 0.5 yrs | 1 – 2 M€ | Specialised contractor |
| | 3. Seismic interpretation, building of sophisticated fault models and constructing of geological models (i.e., site characterisation study) | 0.5 – 1 yrs | 0.5 – 1 M€ | Typical size of area covered: 6 offshore blocks |
| | **Decision gate DG1: 20 M€** | | | |
| Phase 2 | 4. Drilling of exploration well, coring, logging and injection testing | 2 yrs | 20 M€ | Includes lead time for exploration license application; cost is for one well, includes hook-up |
| | 5. Update geological model and feasibility of storing $CO_2$ | 0.5 yrs | 0.5 M€ | Use data obtained from well |
| | **Decision gate DG2: 85 M€** | | | |
| Phase 3 | 6. File license application for storage; complete environmental impact assessment | 1 yr | 0.5 M€ | License approval takes 1 – 2 yrs; activities can continue in parallel |
| | 7. Design, procurement and construction of injection facilities | 2 yrs | 60 M€ | In parallel with license application procedure |
| | 8. Drilling additional well(s) | 1 yr | 20 M€ | Parallel to previous item |
| | 9. Pipeline construction | 1 yr | 2 M€ / km | Costs for high-pressure $CO_2$ pipeline; in parallel to other construction |
| | **Total** | **6-7 yrs** | **110 M€** | Small platform, 2 wells, no compression on platform; pipeline costs not included |

If existing installations can be re-used, significant cost savings can be reached. However, this depends strongly on the local situation, the state of the installations, as discussed in Section 4. Installations from oil production exist in the Q1 block, rendering re-use a possibility, but for the other options re-use is less likely.

### *A.4. Single site or multiple sites?*

It should be emphasized here that if multiple injection sites are required, for example to increase injection rates, the cost is multiplied by the number of locations. If the injection rates obtained with a single injection site are insufficient, an additional well at the same site is not likely to increase the maximum rate significantly. Rates are typically limited by the allowed local pressure increase, not by the number of wells. The combination of reservoir thickness, reservoir permeability and pressure limit largely determines the maximum injection rate. Adding an injection well from the same platform does not necessarily increase this rate. Higher rates can then only be reached by adding an injection point, far from the first site. Here, 'far' is defined in the context of the pressure field in the saline formation. The extent of the pressure footprint of an injection site depends on the properties of the reservoir (such as thickness, permeability, connectivity) and can be estimated with reservoir models. The fact that an additional injection location must be 'far' from existing injection locations implies that new sites are to be developed. Given the dimensions of typical saline formations for $CO_2$ storage, many tens of kilometres across, combining installations between sites is probably limited.

A more detailed explanation of pressure-limited injection rates and an illustration of the pressure footprint of an injection well, can be found elsewhere [8, 9].

### *A.5. Developing a depleted gas field for $CO_2$ storage*

A general site development plan for depleted gas fields is presented here, following recommendations given in an earlier phase of this study [1]. Additional recommendations are given with respect to clusters. The following general workflow including timeline sketches the steps towards developing a depleted gas field from several years prior to the end of production to start of injection. Site development for depleted gas fields is also broken up into three phases, separated by decision gates. The decision gates associated with these phases involve increasingly higher budgets. At each decision gate, the level of knowledge about the risks associated with re-use and conversion is improved and the uncertainties are smaller.

DG0. This is the decision to start a feasibility study, following selection of the site after a screening study (a study similar to Phase 1 of the ISA). The budget to be decided on is about 1 M€.

Phase 1. The first phase typically takes one half to one full year, depending on the size of the field.

DG1. This decision concerns the start of the pre-FEED phase. The budget to be decided on is in the range of 1 – 2 M€.

Phase 2. The second phase takes typically about two years and contains the pre-FEED phase, an environmental impact assessment and license applications.

DG2. A second decision gate occurs when a detailed cost and timing estimate of the site (re-)development is available. The budget to be decided is of the order of several tens of million euros.

Phase 3. The third phase concerns detailed engineering, procurement and construction and takes several years.

### *A.6. Comparison with gas field development for $CO_2$ storage*

The workflows for saline formations and depleted gas fields are similar. Where the starting point for saline formations can be characterized by large uncertainties about the quality of the storage site and a general lack of site and reservoir specific data, the production history of the gas field has resulted in a good knowledge of the reservoir. A large part of the workflow for saline formations is aimed at reaching the level of knowledge and confidence comparable to that for gas fields. The most important data are obtained from the exploratory well and subsequent pilot injection test that occurs in the second phase of the workflow for a saline formation (Table A.1).

Once these data are obtained, the state of knowledge, the assessment of risk and the level of confidence on the performance of the storage complex for a saline formation is comparable to that for a depleted gas field, after the feasibility study.

Figure A.1 illustrates this. It is assumed that 7 years are required for a saline formation and 6 years for a gas field. The three phases in the workflow are indicated by different shades of blue; the decision gates are represented by vertical black lines. The red vertical line represents the second decision gate in the saline formation study, and the first decision gate in the gas field study. At these milestones in the development, the feasibility of storing $CO_2$ for the saline formation can be compared with that for the depleted gas field.

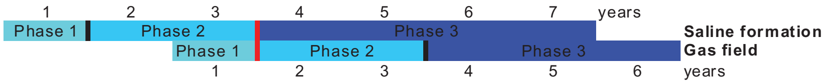


Fig. A.1. Comparison between development timelines for saline formations (top) and gas field (bottom). The solid vertical lines represent decision gates between the different phases; the phases are explained in Table A 1 and Table A 2. A comparable level of knowledge about the storage complex and certainty about safety and security of storage exists after Phase 2 in the development of a saline formation and Phase 1 in that of a gas field (vertical red line).